STATE OF SOUTH CAROLINA
BEFORE THE
PUBLIC SERVICE COMMISSION

DOCKET NO. 2002-223-E

IN RE: APPLICATION OF SOUTH CAROLINA ELECTRIC & GAS COMPANY FOR ADJUSTMENTS IN THE COMPANY'S ELECTRIC RATE SCHEDULES AND TARIFFS

DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF SMI STEEL - SOUTH CAROLINA

November 8, 2002

STATE OF SOUTH CAROLINA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN RE: APPLICATION OF SOUTH CAROLINA ELECTRIC & GAS COMPANY FOR ADJUSTMENTS IN THE COMPANY'S ELECTRIC RATE SCHEDULES AND TARIFFS	)))	**Docket No. 2002-223-E**

DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF
SMI STEEL - SOUTH CAROLINA

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and power pool planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility planning and operating practices, regulatory policy, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Arkansas, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia.

I have previously submitted testimony to the South Carolina Public Service Commission in numerous cases, including two cases involving South Carolina Pipeline Corporation (SCPC): Docket No. 90-452-G (purchased gas review proceeding) and Docket No. 90-452-G (review of SCPC's Industrial Sales Program Rider). I participated but did not file testimony in SCPC’s Docket Nos. 94-202-G (integrated resource plan) and 2001-220-G (SCPC’s open-access gas transportation application). I also filed testimony in Docket Nos. 87-7-E, 87-11-E, 79-7-E (Fall 1988), 90-4-E (Fall 1990), 91-4-E (Fall 1991), and 93-238-E (Spring 1994), which were general rate and fuel cost cases filed by Carolina Power & Light Company (CP&L). In addition, I testified in CP&L's Integrated

Resource Planning case (Docket No. 92-209-E), the Commission's Section 712 wholesale purchased power proceeding (Docket No. 93-231-E), and the Commission's evaluation of a proposed rule governing fuel-cost recovery by electric utilities (Docket No. 93-238-E).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of SMI Steel-South Carolina, one of four minimills in the Steel Group of Commercial Metals Company. SMI Steel is located in Cayce, South Carolina, and is a large industrial customer served by South Carolina Electric & Gas Company (SCE&G). The Cayce facility, which is one of SCE&G's largest retail industrial customers, is an electric minimill that uses an electric arc furnace to melt steel scrap. A continuous casting system processes the molten steel into billets, which are converted into a variety of steel products by a highly automated rolling mill. SMI Steel currently takes firm and interruptible service under SCE&G's Rate 23, real-time pricing rate, and interruptible service rider (Option A).

The Cayce mill employs around 450 people with an annual average wage of approximately $50,000 per employee. Despite a sluggish national economy and especially poor conditions in the steel industry in recent years, SMI has remained in business and has continued to make major economic contributions to the local economy.

Q. HOW DO SMI STEEL'S OPERATIONS AFFECT THE ENVIRONMENT?

A. SMI Steel recycles steel scrap to make new steel. SMI's manufacturing processes produce environmental benefits similar to those produced by other recycling processes—eliminating a major solid waste stream, eliminating the negative effects of obtaining new raw materials (for example, mining), and recapturing and using some of the energy used to produce the steel scrap originally.

Q. WHAT IS SMI STEEL'S INTEREST IN THE CURRENT PROCEEDING?

A. SMI's ability to sell its products in highly competitive domestic and international steel markets depends largely on its ability to control production costs, of which energy costs are a sizable part. Despite numerous energy efficiency improvements that SMI has made at the Cayce plant, energy costs remain a high percentage of total production costs. In the current case, SMI is primarily interested in identifying whether SCE&G's proposed rates and associated proposals are cost-based, likely to promote rate stability, increase cost-effective service options, and create opportunities for reducing costs and using energy more efficiently.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review SCE&G's proposed cost-of-service analyses (including pro forma adjustments) and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed SCE&G's application, testimony, exhibits, and responses to requests for information. I also reviewed information found on web sites operated by the Commission, and by SCE&G and its parent company, SCANA Corporation.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. Cost-of-Service. SCE&G has proposed increasing base revenues by approximately $113 million.[1] In developing proposed rates for its retail electric services, SCE&G first conducted a cost-of-service study for the test year ending March 31, 2002. In this cost analysis, SCE&G allocated and/or directly assigned its costs to functional segments of its retail electric business. The return component of SCE&G's costs reflects a requested 9.93-percent return on rate base and a 12.50-percent return on common equity.

   In allocating demand-related production and transmission costs to major customer classes, SCE&G used a 4-hour average coincident peak (4CP) methodology that the Commission has approved in prior cases. In addition, SCE&G properly removed interruptible demands from the CP estimates since interruptible demands do not cause and should bear no responsibility for its generating and bulk transmission capacity requirements.

2. Revenue Spread. SCE&G spread its proposed $113-million revenue increase among rate classes in a manner that moved some classes closer to and some classes farther from cost of service. In particular, SCE&G moved Residential and Medium General Service rates significantly away from cost of service, while moving rates for Small and Large General Service and Lighting customers closer to cost of service.

   As a result of its proposed revenue spread, SCE&G increased the level of interclass revenue subsidies by about 25 percent—from around $8 million under present rates to more than $10 million under proposed rates. All of the $10 million interclass subsidy created under SCE&G's proposed revenue spread goes to Residential customers.[2] That is, test-year revenues from SCE&G's proposed Residential rates are more than $10 million less than SCE&G's costs (as determined in its cost-of-service study) of serving

[1] The $113-million represents an increase in total operating revenue. The increase in electric sales revenue is about $112 million.
[2] These customers are served under Rates 1, 2, 5, 6, and 8.

this class. SCE&G makes up this shortfall by overcharging General Service and Lighting customers. These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class closer to cost of service.

3. Interruptible Credits. SCE&G currently offer two interruptible service options (Options A and C) to Rate 23 and Rate 24 customers that agree to interrupt their loads under conditions specified in the Interruptible Service rider to these rates. The interruptible service options differ by maximum annual hours of curtailment (150 hours for Option A and 300 hours for Option C) and applicable demand charge credit (Option A—$2.75 per kW of interruptible load, and Option C—$4.50 per kW of interruptible load). SCE&G has proposed no change in the demand-charge credits in this case. This is not unusual since the credits have not been changed since the Commission approved them in 1993.[3]

4. Rates 23 and 24. With respect to rates for Large General Service customers, SCE&G has proposed:

- Overcharging them by approximately $2.1 million. That is, proposed Rates 23 and 24 produce test-year electric sales revenue that is about $2.1 million more than SCE&G's cost of serving these customers.
- Increasing the monthly customer charge component of Rate 23[4] and Rate 24 (which has a separately stated Basic Facilities Charge) by 20 percent—from $1,000 to $1,200 per customer
- Raising demand charges per billing kW by around 6.4 percent.
- Raising energy charges in each rate by smaller percentages.
- Increasing the voltage discount by $0.05 per kW for customers served at 46 kV or above.
- Retaining the present demand charge credits for Interruptible Service Options A and C.

[3] South Carolina Public Service Commission, Docket No. 92-619-E, Order No. 93-465.
[4] The customer charge component of Rate 23 is recovered through the initial demand block (0-1,000 kW).

5. Cope Accelerated Capital Recovery Mechanism. SCE&G has proposed a 3-year extension (through December 31, 2005) for a special accelerated capital recovery mechanism associated with its Cope Generating Station. The mechanism—approved 3 years ago[5] by the Commission—is set to expire December 31, 2002. Under this mechanism, SCE&G may at its discretion accelerate depreciation of the Cope Station—for example, whenever a combination of revenue and expense factors push SCE&G's earnings above allowable levels.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Approve SCE&G's average 4CP methodology to allocate demand-related production and transmission costs. In addition, the Commission should approve SCE&G's exclusion of interruptible loads from the determination of customer class 4CP allocation factors. The Commission has approved SCE&G's 4CP methodology in the past, and should reaffirm its approval in this case.

2. Reject SCE&G's proposed revenue spread. As I noted earlier, under SCE&G's proposal, General Service and Lighting customers pay more than $10 million in interclass revenue subsidies to Residential customers. The Commission should require SCE&G to spread the allowed revenue increase such that interclass revenue subsidies are reduced by at least 75 percent. Reducing interclass subsidies by 75 percent would result in significant movements toward cost-based rates relative to SCE&G's proposal without imposing undue hardship on Residential customers. For example, eliminating 75 percent of the Residential subsidy would increase

---

[5] South Carolina Public Service Commission, Docket No. 1999-389-E, Order No. 1999-655.

the monthly bill of a Residential customer using 800 kWh per month by $0.94. Details of how to implement this revenue spread approach are presented later in my testimony.

3. Reject SCE&G's proposed Rates 23 and 24 and their associated Interruptible Service rider. Instead, the Commission should approve, in conjunction with my recommended revenue spread, the following revisions to SCE&G's proposal:

   - Reduce Rate 23's demand charge to $11.53 per kW of billing demand—which also reduces the first-block demand charge to $12,730 from SCE&G's proposed $12,770.
   - Reduce Rate 24's Summer-Peak demand charge to $14.56 from $14.60 per kW, Off-Peak demand charge to $4.20 from $4.40 per kW, and Off-Peak energy charge to $0.02139 from $0.02160 per kWh. The Off-Peak demand charge change reflects the need to temper the dramatic increase in this charge in the past 10 years relative to the modest increases in Rate 24's Summer-Peak demand charge.
   - Increase the Interruptible Service demand charge credits. The Option A credit should be increased from $2.75 to $3.25 per kW of interruptible demand, and the Option C credit should be increased from $4.50 to $5.25 per kW of interruptible demand. These changes are necessary to reflect more accurately SCE&G's cost of serving interruptible load. In addition, the higher credits are necessary to reestablish the relative value of the credits within each rate. For example, in 1993 the Option C credit ($4.50 per kW) was about 47 percent of the Rate 23 demand charge ($9.60 per kW). In contrast, today the Option C credit is only about 39 percent of SCE&G's proposed Rate 23 demand charge ($11.57 per kW). Increasing the Option C credit to $5.25 per kW will raise this percentage from about 39 percent to around 45 percent—still slightly below the credit's relative value in 1993.

4. Reject SCE&G's proposed extension of the Cope Generating Station accelerated capital recovery mechanism. In its 1999 order approving the mechanism, the Commission justified the mechanism as a means for SCE&G to avoid potential stranded costs in competitive retail markets. Retail open access does not exist in South Carolina and competitive retail markets are unlikely to emerge in the state in the near future. There is no justification today for the accelerated capital recovery mechanism. If it remains in effect through 2005, the only beneficiaries will be SCE&G's management and the stockholders of its parent company SCANA. Allowing the mechanism to remain in effect will enable SCE&G to internalize excess earnings with no commensurate benefit to ratepayers. The Commission should ensure that the mechanism ends as planned on December 31, 2002.

COST OF SERVICE

GENERAL APPROACH

Q. HOW DID SCE&G ALLOCATE ITS COSTS TO CUSTOMER CLASSES?

A. SCE&G conducted a detailed cost-of-service study using data (adjusted in many cases for known and measurable changes) for the test year ending March 31, 2002. In this cost analysis, SCE&G allocated and/or directly assigned its costs to functional segments of its retail electric business. The return component of SCE&G's costs reflects a requested 9.93-percent return on rate base and a 12.50-percent return on common equity.

Q. IS THE COST-OF-SERVICE METHODOLOGY THAT SCE&G USED REASONABLE?

A. Yes. The methodology basically follows guidelines set in the NARUC *Electric Utility Cost Allocation Manual.* For example, SCE&G has properly classified all distribution costs as either demand- or customer-related costs since distribution costs have no energy-related component.

Q. DO YOU AGREE WITH SCE&G'S CHOICE OF ALLOCATORS TO ASSIGN DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS?

A. Yes. In allocating demand-related production and transmission costs to major customer classes, SCE&G used a 4-hour average coincident peak (4CP) methodology that the Commission has approved in prior cases. In general, this approach is reasonable and should be approved since it reflects the key determinant of SCE&G's need for bulk power facilities.

Q. WHY IS THE REASONABLENESS OF A COST-OF-SERVICE METHODOLOGY IMPORTANT?

A. Cost of service identifies and assigns cost responsibility to customer classes. Specific rates can then be developed to recover each class' cost-based revenue requirement, resulting in prices that recover the utility's cost of service in an equitable and efficient manner. If the cost-of-service methodology does not allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced—thereby causing customers to make inefficient electricity investment and consumption decisions.

SCE&G has employed a reasonable cost-of-service methodology in this case to allocate and assign its costs to customer classes. However, as I discuss in more detail later, SCE&G deviated from the results of its cost study in assigning its proposed revenue increase to customer classes.

TREATMENT OF INTERRUPTIBLE LOAD

Q. WHAT IS INTERRUPTIBLE OR NONFIRM SERVICE?

A. Interruptible service is a separate utility product that allows a supplier to interrupt or curtail customer loads when reliability is impaired. Interruptible load enables a supplier to maximize the value of its existing reserve capacity and to avoid installing new capacity. The available supply of interruptible service depends on the relationship between available capacity and firm service demands. That is, if firm demands command all available generating capacity, the supply of interruptible service falls to zero. When firm demands are significantly less than available capacity, the supply of interruptible service is significantly greater.

Q. WHAT TYPES OF INTERRUPTIBLE SERVICE DOES SCE&G OFFER?

A. SCE&G currently offers two types of interruptible service under its Interruptible Service rider to Rates 23 and 24. Under Option A, a customer agrees to curtail interruptible load up to 150 hours annually when requested by SCE&G during hours specified in the service rider. In exchange for agreeing to curtail load when requested, the customer receives a credit of $2.75 per kW of interruptible demand against applicable demand charges in Rate 23 or Rate 24. Option C is similar except that annual maximum curtailment hours are 300 instead of 150 and the demand charge credit is $4.50 per kW of interruptible demand instead of $2.75 per kW. (See Table 1 below.)

Table 1. SCE&G Interruptible Service Options

Option	Max. Curtailment Hrs.	Credit ($/kW)
A	150	2.75
C	300	4.50

Q. DOES SCE&G DERIVE BENEFITS FROM INTERRUPTIBLE CUSTOMERS?

A. Yes. SCE&G achieves demand-side management (DSM) benefits associated with capacity-cost savings by excluding interruptible load from its peak-load capacity requirements. For example, in his direct testimony, SCE&G's James C. Landreth said:

> The capacity needs for 2002 and 2004 discussed above take into account 240 MW of demand-side management, most of which is related to interruptible load.[6]

When asked about the details of this 240 MW of DSM, SCE&G's responded:

[6] James M. Landreth, Docket No. 2002-223-E, direct testimony at page 4, lines 11-13.

> The 240 MWs of DSM is comprised of 184 MW of interruptible load, 40 MWs of standby generator capacity, and 16 MWs of SEPA capacity.…The 240 MWs is assumed to ***displace*** 240 MWs of installed or purchased peaking capacity.[7] (emphasis added)

That is, SCE&G does not build capacity to serve interruptible load. In addition, properly priced and structured interruptible service promotes economic growth and jobs associated with competitive industrial electricity prices, and increased planning flexibility.

Q. DOES INTERRUPTIBLE LOAD OFFER BENEFITS RELATIVE TO COMBUSTION TURBINE CAPACITY?

A. Yes. First, environmental impacts of constructing and operating combustion turbines are avoided if interruptible load displaces the need for such capacity. Second, selling interruptible service reduces a utility's short- and long-term financial investment risk relative to building capacity to serve an equivalent amount of firm service. For example, remaining customers may be forced to absorb stranded generation investment costs associated with the loss of a large firm-service load. Such costs cannot occur if an interruptible customer leaves the system.

Q. WHAT IS THE APPROPRIATE COST BASIS FOR PRICING INTERRUPTIBLE SERVICE?

A. Prices for nonfirm (interruptible) service should reflect a supplier's short-run marginal cost of electricity—which includes marginal fuel or purchased power cost, nonfuel O&M expenses, and delivery losses. From a theoretical perspective, including any capacity-related costs in interruptible prices is not appropriate.

---

[7] See SCE&G's response to SMI 3.2.a and c.

Q. DO RECOGNIZED AUTHORITIES SUPPORT YOUR CONTENTION THAT INTERRUPTIBLE SERVICE SHOULD BE PRICED ON THE BASIS OF SHORT-RUN MARGINAL COST OF SERVICE?

A. Yes. In his discussion of long-run versus short-run marginal cost pricing when utilities are adding capacity, the noted authority on the economics of utility regulation, Dr. Alfred E. Kahn, states that price:

> ...approximations to SRMC must be confined largely to (1) incorporation in rate schedules, insofar as prediction is possible, (2) the offer of special *rates for interruptible service*, and (3) exemption of clearly off-peak pricing from capacity charges.[8] (Footnotes omitted, emphasis added.)

According to Dr. Kahn, short-run marginal cost—which by definition excludes capacity- or demand-related costs—should be the basis for pricing interruptible service. He concludes that "even the LRMC [long-run marginal cost] of definitely off-peak business (and interruptible service is by definition off-peak) includes no capacity costs either."[9]

Another recognized authority, Professor James C. Bonbright, advocated pricing interruptible service on the basis of marginal costs that reflect no capacity-related cost of service:

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer-connected spur lines and substations) and energy costs (e.g., fuel and incremental maintenance cost) actually incurred and ***no capacity pricing cost should be included in pricing interruptible service***.
>
> While some feel that it is an impropriety to treat interruptible customers as if they were firm customers, they still opine that it would be fair and reasonable to obtain a small contribution from them for capacity costs. This is debatable.[10] (emphasis added.)

---

[8] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions, Volume I*, New York: John Wiley & Sons, Inc., 1970, page 108.
[9] *Ibid.* at footnote 61.
[10] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, Virginia: Public Utilities Reports, Inc., 1988, page 502.

Q. SHOULD AN INTERRUPTIBLE RATE RECOVER ANY EMBEDDED OR FIXED PRODUCTION AND TRANSMISSION COSTS?

A. No. Fundamental economic theory demonstrates that interruptible customers do not cause the utility to incur embedded production and bulk transmission costs. However, eliminating all or most embedded fixed-cost recovery almost always causes embedded cost advocates to raise fallacious but politically attractive "free rider" arguments.

Q. DOES SCE&G PRICE ITS INTERRUPTIBLE SERVICE ON THE BASIS OF SHORT-RUN MARGINAL COST OF SERVICE?

A. No. Prices reflected in SCE&G's rates are based on embedded costs used in its cost-of-service analyses. The interruptible demand charge credits simply reduce the stated billing demand charges in Rates 23 and 24—rates based on embedded costs, not marginal costs. By setting the credits significantly below demand charges in Rates 23 and 24, SCE&G ensures that interruptible customers make a major contribution to recovery of its fixed demand-related production and transmission costs. As long as SCE&G prices interruptible service by discounting firm-service, embedded-cost rates, determining the appropriate discount will remain a contentious public policy issue.

Q. IS SCE&G'S INTERRUPTIBLE SERVICE PRICING CONSISTENT WITH ITS TREATMENT OF INTERRUPTIBLE DEMAND IN ITS COST-OF-SERVICE ANALYSIS?

A. No. In its cost analysis, SCE&G properly removed interruptible demands from the 4CP estimates used to allocated demand-related production and transmission costs—thereby allocating none of these costs to interruptible customers.[11] This approach is proper since interruptible demands do not cause and should bear no responsibility for its generating and bulk transmission capacity requirements. In contrast, SCE&G's interruptible rates—even for customers served at transmission

[11] See SCE&G's response to SMI 3.15.b.

voltages—collect more than half of the demand-related costs included in firm-service Rates 23 and 24. Since the bulk of these costs reflect production and transmission functions, interruptible customers are paying costs for which even SCE&G agrees they are not responsible.

Q. HAS THE RELATIVE VALUE OF THE DEMAND CHARGE CREDITS REMAINED CONSTANT IN THE PAST TEN YEARS?

A. No. Since 1993 interruptible customers have paid an increasingly high proportion of the demand charges in Rates 23 and 24 because demand charges in the rates have continued to increase while the interruptible demand charge credits have remained unchanged. For example, as shown in Table 2 below, in 1993 the Option A credit was about 29 percent of the Rate 23 firm service demand charge. However, today the Option A credit is less than 24 percent of SCE&G's proposed Rate 23 demand charge. The decline in the relative value of the Option C credit has been even more pronounced—going from around 47 percent in 1993 to less than 39 percent of SCE&G's proposed Rate 23 demand charge.

Table 2. Interruptible Credits as Percentage of Rate 23 Demand Charge

Option	1993	1994	2002	Proposed
A	28.65	28.12	25.30	23.77
C	46.88	46.01	41.40	38.89

Q. HAS A SIMILAR TREND OCCURRED WITH RESPECT TO THE RELATIVE VALUE OF INTERRUPTIBLE DEMAND CHARGE CREDITS ASSOCIATED WITH RATE 24?

A. Yes. As shown in Table 3 below, since 1993 the Option A credit as a percentage of Rate 24's firm service demand charges has fallen from about 29 percent to less than 24 percent. The relative value of the Option C credit has declined from around 48 percent in 1993 to 39 percent today.

Table 3. Interruptible Credits as Percentage of Rate 24 Demand Charges

Option	1993	1994	2002	Proposed
A	29.27	28.50	25.36	23.83
C	47.89	46.64	41.51	39.00

Note: weighted average of summer and non-summer peak demand charges used in calculations.

Q. DOES SCE&G'S DIRECT TESTIMONY ADDRESS THE LEVEL OF INTERRUPTIBLE CREDITS?

A. No. However, in response to an interrogatory, SCE&G stated:

> The Company is not actively marketing the program but continue (*sic*) to honor its existing interruptible contracts. Accordingly, and in the interest of rate stability, the Company has not proposed any change in these rates.[12]

Similarly, in response to another interrogatory, SCE&G stated that it reviewed "…monthly fixed charges of an internal combustion turbine (ICT)…in evaluating the interruptible credit for this proceeding."[13] SCE&G found that the fixed charges ranged from:

> …a high of $6.13 and a low of $3.71 per kw per month. Based on this information, the Company believes the interruptible credits as shown in this proceeding are priced appropriately given the limited hours of interruption for each option vs. the annual availability of an ICT.[14]

Q. DO YOU AGREE WITH SCE&G THAT ITS INTERRUPTIBLE CREDITS ARE PRICED APPROPRIATELY?

A. No. I pointed out earlier that the relative value of the interruptible credits has declined significantly since 1993. With respect to SCE&G's fixed charge rate analysis, the analysis has at least two major flaws

- SCE&G's use of an economic fixed charge rate to evaluate the reasonableness of an embedded-cost interruptible credit is inappropriate. An economic carrying charge must be adjusted annually by the inflation rate, implying that cost recovery increases

[12] See SCE&G's response to SMI 3.2.d.
[13] See SCE&G's response to SMI 3.27.a and b.
[14] *Ibid*.

over the life of the combustion turbine asset. In contrast, under embedded-cost ratemaking, cost recovery of an asset declines over time as the asset is depreciated—that is, traditional embedded-cost ratemaking is front-loaded. Using an economic fixed charge rate to evaluate SCE&G's interruptible credits ensures that credits will always be understated relative to the cost of peaking capacity that interruptible load displaces.[15] SCE&G's levelized fixed charge rate analysis produces a more reasonable picture of the value of interruptible load. This analysis indicates that the interruptible credits should fall within a range of $4.77 per kW to $6.12 per kW per month.

- SCE&G's analysis ignores transmission and fuel-cost savings attributable to interruptible load. As a result, even SCE&G's levelized fixed charge rate analysis understates the appropriate level of interruptible credits.

Q. DOES SCE&G'S FIXED CHARGE RATE ANALYSIS PROVIDE ANY USEFUL GUIDANCE WITH RESPECT TO THE APPROPRIATE LEVEL OF CREDITS FOR ITS INTERUPTIBLE SERVICE OPTIONS?

A. Yes. The levelized fixed charge rate analysis clearly indicates that the value of peaking capacity offset by interruptible load lies between $4.77 per kW and $6.13 per kW. This range can serve as a starting point for evaluating the reasonableness of SCE&G's interruptible demand charge credits—particularly the Option C credit. I will recommend specific credits after discussing the spread of SCE&G's proposed revenue increase among customer classes.

[15] SCE&G admits that it does not use the economic fixed charge rate in setting rates and charges. See SCE&G's Supplemental Answer to SMI 6.13.

REVENUE SPREAD

Q. WHAT INCREASE IN REVENUE IS SCE&G REQUESTING?

A. SCE&G's requested increase in operating revenue is $112.8 million (9.18 percent), while the increase in electric sales revenue is $111.9 million (9.61 percent).

Q. WHAT APPROACH DID SCE&G USE TO SPREAD THE PROPOSED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. SCE&G did not specify a clear approach for spreading its requested increase among customer classes. For example, SCE&G stated:

> Many factors have to be considered in developing an appropriate distribution of revenue to the various classes. The *cost of service* is the *most important component* of rate design, but other factors also serve as guides to proper rate design. These remaining factors are value of service, our rate history, revenue stability, improvement of system load factor, and optimum use of natural resources.[16] (emphasis added)

Q. DID SCE&G ELABORATE ON THESE OTHER FACTORS?

A. Yes. In response to an interrogatory, SCE&G discussed in general terms the relative importance of these factors. However, SCE&G cited three specific factors that appear to have played a dominant role in the revenue spread. Quoting from the interrogatory response, SCE&G cited:

> - The sensitivity to substantial rate movement of the residential customers (which includes a broad range of people with differing economic circumstances);
> - The greater price elasticity of large general service customers (particularly as it relates to industrial development, global competitiveness and plant and production decisions); and
> - The fact that disproportional peak demand increase of medium general service customers and their eroding load factor mean that they have disproportionately contributed to the cost causation.[17]

---

[16] John R. Hendrix, Docket No. 2002-223-E, direct testimony at page 8, lines 12-17.
[17] See SCE&G's response to SCMA 1.5

Q. WHAT WERE THE RESULTS OF SCE&G'S REVENUE SPREAD USING THIS APPROACH?

A. As a result of using this approach to spread its proposed revenue increase:

- Residential and Large General Service customers received below-average increases and other classes received above-average increases. (See Exhibit DWG-1.)
- SCE&G set proposed rates for the Residential class $10 million below cost of service (measured by the class' revenue subsidy and reflected in its RORI—relative rate of return index). In contrast, SCE&G set rates for other classes above cost of service—$2.1 million above for Large General Service, $2.3 million above for Small General Service, and $5.4 million above for Medium General Service customers.
- Compared to present rates, SCE&G's proposed revenue spread moved Residential and Medium General Service rates significantly away from cost of service, while moving rates for Small and Large General Service and Lighting customers closer to cost of service.
- SCE&G increased the level of interclass revenue subsidies by about 25 percent—from around $8 million under present rates to more than $10 million under proposed rates. All of the $10 million interclass subsidy created under SCE&G's proposed revenue spread goes to Residential customers.[18] That is, test-year revenues from SCE&G's proposed Residential rates are more than $10 million less than SCE&G's costs (as determined in its cost-of-service study) of serving this class.

Q. WHAT ARE INTERCLASS REVENUE SUBSIDIES?

A. Interclass subsidies reflect the amount by which revenue from a customer class exceeds or falls short of the class' cost responsibility, which is determined in SCE&G's class cost-of-service study. In general, a class receives (pays) an

[18] These customers are served under Rates 1, 2, 5, 6, and 8.

interclass subsidy if its rate revenue is less than (greater than) its assigned cost of service at the system average rate of return.

Q. IS SCE&G'S REVENUE SPREAD APPROACH REASONABLE?

A. No. SCE&G's revenue spread moves Residential and Medium General Service rates significantly away from cost of service, increases interclass revenue subsidies, and imposes unjustified increases on Medium General Service customers.

Q. WHO PAYS THE $10-MILLION SUBSIDY THAT RESIDENTIAL CUSTOMERS RECEIVE UNDER SCE&G'S REVENUE SPREAD?

A. SCE&G makes up the $10-million revenue shortfall caused by the Residential subsidy by overcharging General Service and Lighting customers. (See Exhibit DWG-1 and Table 4 below.) These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class closer to cost of service.

Table 4. Interclass Subsidies Under SCE&G's Proposal ($000)

Class	RORI	Subsidy
Res	95.71	10,091
SGS	102.05	(2,268)
MGS	109.48	(5,405)
LGS	101.92	(2,081)
StLgt	102.36	(336)
Total Retail	100.00	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-1.

Q. IS SCE&G'S PROPOSED INCREASE TO MEDIUM GENERAL SERVICE CUSTOMERS JUSTIFIED ON THE BASIS OF THE CLASS' DEMAND GROWTH?

A. No. As I noted earlier, SCE&G claims that because of rapid load growth and eroding load factor, Medium General Service customers "have disproportionately contributed to the cost causation." SCE&G further states:

> In regards to the medium general service class, moving their relative return from 101% to 109% was partly due to the fact that their CP demand increased from the last rate case by 38%, the largest increase of any class. Therefore, from a cost causation standpoint, it is appropriate to allocate the revenue increase as proposed.[19]

SCE&G is correct that between 1995-2002, the CP demand for Medium General Service customers increased by 38 percent.[20] However, CP demands for other classes also grew during this period—Residential demands increased nearly 27 percent. In addition, following SCE&G's logic, Street Lighting customers should have received no rate increase since this class did not contribute to any growth in SCE&G's system peak demand. Nonetheless, SCE&G has proposed an increase for Street Lighting customers (13.96 percent) that exceeds its proposed increase for Medium General Service customers (13.42 percent). The fallacy of SCE&G's logic is demonstrated by its cost-of-service study, which clearly shows that the cost-based increase for the Street Lighting class should be well above the system average increase and also above the increase for the Medium General Service class. For example, as shown in Exhibit DWG-1, a 14-percent rate increase only pushes the RORI for the Street Lighting class to 102—indicating that rates reflecting such an increase would only be slightly higher than cost of service—while a slightly lower increase pushes the RORI for Medium General Service customers to over 109.

Q. HAVE YOU DEVELOPED AN ALTERNATIVE REVENUE SPREAD THAT MOVES RATES CLOSER TO COST OF SERVICE?

A. Yes. I recommend that the Commission reject SCE&G's proposed revenue spread. Instead, the Commission should require SCE&G to spread the allowed sales revenue increase such that interclass revenue subsidies are reduced by at least 75 percent. As shown in Exhibit DWG-2, reducing the interclass subsidies by 75 percent creates a more equitable and efficient distribution of SCE&G's proposed sales revenue increase without imposing unjust and unreasonable

---

[19] See SCE&G's response to SCMA 1.6.
[20] See SCE&G's response to SMI 3.15 for data used to calculate CP growth rates.

increases on any class. The increases by customer class resulting from this revenue spread approach are summarized in Table 5 below.

Table 5. Recommended Sales Revenue Spread

Class	**Increase Amount ($000)**	**Increase Percent**	**Subsidy ($000)**
Res	47,680	9.40	2,523
SGS	31,063	14.19	(567)
MGS	13,196	10.27	(1,351)
LGS	16,453	5.81	(520)
StLgt	3,506	13.02	(84)
Total Retail	111,898	9.61	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-2.

Q. DOES YOUR RECOMMENDED REVENUE SPREAD ELIMINATE INTERCLASS SUBSIDIES?

A. No. My recommended revenue spread only reduces the subsidies by 75 percent. As shown in Table 5 above, Residential customers would still receive a sales revenue subsidy of almost $2.5 million, of which almost 97 percent would be paid in above-cost rates by General Service customers.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED REVENUE SPREAD ON RESIDENTIAL CUSTOMERS RELATIVE TO SCE&G'S REVENUE SPREAD?

A. The impact on Residential customers is quite modest. For example, eliminating 75 percent of the Residential subsidy would increase the monthly bill of a Residential customer using 800 kWh per month by $0.94.

Q. IF THE COMMISSION ALLOWS LESS THAN SCE&G'S REQUESTED SALES REVENUE INCREASE, HOW SHOULD THE APPROVED INCREASE BE SPREAD?

A. I recommend that any allowed sales revenue increase be spread in proportion to the spread shown in Exhibit DWG-2 and Table 5 above. For example, Residential customers should get 42.61 percent ($47,680 divided by $111,898) of any allowed sales revenue increase.

RATE DESIGN

Q. SHOULD THE COMMISSION APPROVE SCE&G'S PROPOSED RATES 23 AND 24 AND THEIR ASSOCIATED INTERRUPTIBLE SERVICE RIDER?

A. No. The Commission should reject SCE&G's proposed design of Rates 23 and 24 and the Interruptible Service rider associated with these rates. Instead, the Commission should approve, in conjunction with my recommended revenue spread, revisions to these rates and rider that reduce selected demand and energy charges and increase the Interruptible Service demand charge credits. These changes can be achieved within the constraints imposed by my recommended revenue spread.

Q. WHAT SPECIFIC CHANGES ARE YOU RECOMMENDING TO SCE&G'S PROPOSED RATES 23 AND 24?

A. I recommend:

- Reducing Rate 23's demand charge to $11.53 per kW of billing demand—which also reduces the first-block demand charge to $12,730 from SCE&G's proposed $12,770.
- Reducing Rate 24's Summer-Peak demand charge to $14.56 from $14.60 per kW, Off-Peak demand charge to $4.20 from $4.40 per kW, and Off-Peak energy charge to $0.02139 from $0.02160 per kWh. The change in the Off-Peak demand charge reflects the need to temper the dramatic increase in this charge in the past 10 years relative to the modest increases in Rate 24's Summer-Peak demand charge. More specifically, since 1993 Rate 24's Off-Peak demand charge has increased from $2.60 to $4.40 (SCE&G proposed) per kW—a 69-percent increase. In contrast, the Summer-Peak demand

charge has only increased from $13.90 to $14.60 (SCE&G proposed) per kW—a 5-percent increase. Since SCE&G claims that its capacity needs are driven by summer peak demands, the appropriateness of the substantial increase in the off-peak demand charge relative to the summer-peak demand charge is questionable.

Q. WHAT CHANGES ARE YOU RECOMMENDING FOR THE INTERRUPTIBLE SERVICE DEMAND CHARGE CREDITS?

A. I recommend increasing the Option A credit from $2.75 to $3.25 per kW of interruptible demand, and increasing the Option C credit from $4.50 to $5.25 per kW of interruptible demand. These changes are necessary to reflect more accurately SCE&G's cost of serving interruptible load. As I noted earlier, SCE&G's levelized fixed charge rate analysis clearly indicates that the value of peaking capacity offset by interruptible load lies between $4.77 per kW and $6.13 per kW per month—significantly above SCE&G's proposed credits..

To check the reasonableness of SCE&G's fixed charge rate analysis, I conducted an analysis using the levelized fixed charge rate (16.34 percent) developed in SCE&G's analysis. I applied this rate to the total installed cost of SCE&G's Urquhart Combustion Turbine No. 4—a recent plant addition—to estimate the annual and monthly revenue requirements associated with this plant's embedded production capital costs.[21] The results of my analysis indicate a monthly revenue requirement of $6.01 per kW of peaking capacity. This value falls within the upper boundary of the cost range estimated by SCE&G—$6.13 per kW per month. Again note that these values reflect only the cost of peaking capacity that interruptible load can displace. They do not reflect transmission plant and fuel costs avoided as a result of demands being interruptible.

[21] See SCE&G's responses to SMI 3.5 and 3.27.

Q. WHY HAVE YOU RECOMMENDED DIFFERENT INCREASES IN THE OPTION A AND OPTION C CREDITS?

A. My recommended increases were limited by my recommended revenue spread and associated subsidy reductions—about $1.56 million for Large General Service customers. In addition, I have recommended a smaller increase for Option A to reflect the option's lower curtailable hours (150) relative to curtailable hours (300) under Option C.

Q. OF THE $1.56-MILLION REDUCTION IN THE LARGE GENERAL SERVICE SUBSIDY, HOW MUCH IS ACCOUNTED FOR BY YOUR RECOMMENDED INCREASES IN THE INTERRUPTIBLE DEMAND CHARGE CREDITS?

A. Increasing the credits as recommended reduces sales revenue from the Large General Service class by approximately $910,000—about 58 percent of the $1.56-million subsidy reduction. The remainder of the subsidy reduction is used to cover my other recommended changes to Rates 23 and 24.

Q. WILL YOUR RECOMMENDED CREDITS RESTORE THE ORIGINAL RELATIVE VALUE RELATIONSHIP OF CREDITS AS A PERCENTAGE OF FIRM-SERVICE DEMAND CHARGES?

A. In general, the higher credits will reestablish the relative value of the credits within each rate. For example, in 1993 the Option A (C) credit was about 29 (47) percent of Rate 23's demand charge. This relative value relationship declined from 1993 to 2002 as Rate 23's demand charge rose without a corresponding increase in the interruptible demand charge credits. With my recommended credits, this relative value relationship will be reestablished. (See Table 6 below.)

Table 6. Interruptible Credits as Percentage of Rate 23 Demand Charge

Option	1993	SCEG-02	SMI-02
A	28.65	23.77	28.09
C	46.88	38.89	45.38

Q. WHAT EFFECT WILL YOUR RECOMMENDATIONS HAVE ON THE RELATIVE VALUE OF INTERRUPTIBLE CREDITS ASSOCIATED WITH RATE 24?

A. As shown in Table 7 below, my recommended $3.25 per kW Option A credit and $5.25 per kW Option C credit will raise the relative value of the credits almost to their 1993 levels. For example, the Option C credit was about 48 percent of Rate 24's weighted average peak demand charges in 1993. My recommended $5.25 per kW credit will help to reestablish this relative value relationship.

Table 7. Interruptible Credits as Percentage of Rate 24 Demand Charges

Option	1993	SCEG-02	SMI-02
A	29.27	23.83	28.17
C	47.89	39.00	45.50

Note: weighted average of summer and non-summer peak demand charges used in calculations.

Q. HAVE YOU SUMMARIZED YOUR RECOMMENDED CHARGES FOR RATES 23 AND 24 AND THEIR ASSOCIATED INTERRUPTIBLE SERVICE RIDER?

A. Yes. My recommended charges for Rate 23, Rate 24, and the associated interruptible rider are shown in Exhibit DWG-3.

COPE ACCELERATED CAPITAL RECOVERY MECHANISM

Q. PLEASE DESCRIBE THE ACCELERATED CAPITAL RECOVERY MECHANISM ASSOCIATED WITH SCE&G'S COPE GENERATING STATION.

A. Under the mechanism, SCE&G may at its discretion accelerate depreciation (up to $36 million annually) of the Cope Generating Station—for example, whenever a combination of revenue and expense factors push SCE&G's earnings above allowable levels. The mechanism expires December 31, 2002.

Q. WHY WAS THE MECHANISM APPROVED IN 1999?

A. In its August 1999 application seeking the Commission's approval of the accelerated capital recovery mechanism,[22] SCE&G cited the Cope Station's above-average cost and the plant's potential exposure to stranded costs as factors supporting SCE&G's need for the mechanism. In its September 1999 order approving the mechanism,[23] the Commission stated:

> Upon consideration of this matter, the Commission is of the opinion, and so finds, that the proposed accounting treatment contained in the Application filed by SCE&G and described above should be approved for the reasons stated in the Application. Given the uncertainty of electric deregulation and the potential for the limitation of recovery of the Company's investments in its generating assets, we believe the accelerated capital recovery makes sense, especially since no electric rate increase for the Company's customers would result from the adoption of this plan.[24]

Q. HAS SCE&G REQUESTED AN EXTENSION OF THE ACCELERATED CAPITAL RECOVERY MECHANISM?

A. Yes. In this case SCE&G has requested a 3-year extension (through December 31, 2005).

Q. SHOULD THE COMMISSION APPROVE THE 3-YEAR EXTENSION?

A. No. Retail access does not exist in South Carolina and competitive retail markets are unlikely to emerge in the state in the near future. As a result, SCE&G has no stranded-cost problem, and there is no justification today for the accelerated capital recovery mechanism. If it remains in effect through 2005, the only potential beneficiaries will be SCE&G's management and stockholders of the parent company SCANA. Allowing the mechanism to remain in effect will enable SCE&G to internalize excess earnings with no commensurate benefit to

---

[22] South Carolina Public Service Commission, Docket No. 1999-389-E, SCE&G application dated August 25, 1999. The application was filed only nine months after the Commission had reduced SCE&G's rates by about $22.7 million annually because SCE&G's earnings exceeded authorized levels. See South Carolina Public Service Commission, Docket No. 98-623-E, Order No. 98-987 dated December 11, 1998.
[23] South Carolina Public Service Commission, Docket No. 1999-389-E, Order No. 1999-655.
[24] Order No. 1999-655 at page 4.

ratepayers. That is, the mechanism will force ratepayers to forego potential rate reductions if SCE&G earnings exceed authorized levels. The Commission should ensure that the mechanism ends as planned on December 31, 2002.

Q. WHAT DO YOU RECOMMEND REGARDING THE COPE ACCELERATED CAPITAL RECOVERY MECHANISM?

A. I recommend that the Commission reject SCE&G's proposed extension of the Cope Generating Station accelerated capital recovery mechanism

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.